ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/95-15
50-323/95-15

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

Inspection At: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: September 15 through October 28, 1995

Inspectors: J. Russell, Acting Senior Resident Inspector
S. Boynton, Resident Inspector
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Approved: Howard J. Wong 11/22/95
H. J. Wong, Chief, Reactor Projects Branch E Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, onsite followup to events, plant maintenance, surveillance observations, onsite engineering, and plant support activities.

Results (Units 1 and 2):

Operations:

- With Unit 1 in Mode 6 and steam generator nozzle dams installed, operators reenergized a 12 Kilo Volt (kV) non-Class 1E bus with a grounding device installed, causing a loss of offsite power to Unit 1 for approximately 16 hours. This will be reviewed as a special inspection in NRC Special Inspection Report 50-275/95-17 (Section 3.1).

- Operator actions were good in response to a Unit 2 manual trip and a fire in a Unit 1 electrical penetration box (Section 2.1).

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- An NRC inspector identified inoperable recorders on both Units post accident monitoring panels, and communication weaknesses during a Unit 2 plant startup, indicating more attention was needed in these areas (Sections 2.3 and 2.6).

Maintenance:

- Specific maintenance deficiencies associated with the Unit 1 loss of offsite power while shutdown will be discussed in NRC Special Inspection Report 50-275/95-17 (Section 3.1).
- Maintenance activities on a Unit 1 main steam isolation valve and a Unit 1 reactor coolant pump seal evidenced some weakness in foreign material exclusion (Sections 4.1 and 4.2).
- Vendor recommended preventative maintenance for pin lubrication was not being accomplished on main steam isolation valves (Section 6.1.3).

Engineering:

- Licensee engineers discovered by fiber optic inspection that two main steam isolation valves were not fully shut, after core alterations had commenced, in violation of Technical Specifications. This problem had been noted by engineering personnel a year earlier, but planned procedural changes had not been implemented (Section 6.1).
- The licensee performed a performance test on a Unit 1 component cooling water (CCW) heat exchanger and found that the heat transferred to CCW in certain design basis accidents could be greater than assumed in plant design. Appropriate compensatory measures were established (Section 6.2).
- The licensee identified that reactor coolant pump secondary breaker position contacts in the plant protection system had not been tested since installation approximately 10 years ago. These contacts were not required to be tested by Technical Specifications, but the licensee incorporated them in the surveillance program (Section 6.3).
- Setpoint deviations in the lift pressure of the Unit 2 main steam safety valves self evidenced during a unit trip. The licensee performed an extensive root cause evaluation, applied for and received an emergency Technical Specification change, and developed corrective actions to prevent recurrence (Section 6.4).

Plant Support:

- The three non-cited violations involved personnel failures to follow applicable procedures and were related to: failure to post/label a bucket containing highly radioactive debris suspended underwater on a

rope; an unlocked high-high radiation area door; and inadequate postings during radiography operations (Section 7.2).

- A non-cited violation in the security area involved the NRC inspector finding an unattended protected area badge in the protected area in the Unit 1 Turbine building (Section 7.1).

Summary of Inspection Findings:

- Violation 50-275/9515-01 was identified (Section 6.1).
- Four Non-Cited Violations were identified (Section 7.1, 7.2.1, 7.2.2, and 7.2.3).
- Inspector Followup Item 50-275/9515-02 was opened.
- Inspector Followup Item 50-275/9515-03 was opened.

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - List of Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 operated at 100 percent power until September 15, 1995, when reactor power was lowered to 50 percent for circulating water system tunnel cleaning. On September 17, 1995, power was raised to 100 percent. Power remained at 100 percent until September 30, 1995, when the unit was shut down for the cycle 7 refueling outage. The core was offloaded on October 6, 1995, and the core was reloaded on October 19, 1995. On October 21, 1995, the licensee declared a Notice of Unusual Event when offsite power was lost to the unit for 16 hours due to a maintenance error which caused the loss of 25 - 12 kV Auxiliary Transformer 1-1 while the Unit 1 startup transformers were undergoing maintenance. The emergency diesel generators started and provided power for the unit shutdown cooling loads. Offsite power was reestablished on October 16, 1995, via the startup transformers. The catastrophic failure of Auxiliary Transformer 1-1, prevented backfeeding power via the main transformers for the remainder of the inspection period. The unit remained in Mode 6 until the end of the inspection period.

1.2 Unit 2

Unit 2 operated at 100 percent until September 23, 1995, when power was lowered to 50 percent and the reactor was manually tripped due to an influx of sea kelp. The sea kelp caused a traveling screen to fail and reduced main circulating water system flow. The unit remained in Mode 3 until October 2, 1995, when the unit was restarted and the main turbine generator was synchronized to the grid. The unit was again brought to 100 percent power on October 5, 1995, and remained at 100 percent power until the end of the inspection period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Unit 2 Manual Reactor Trip

Background - On September 23, 1995, reactor power was reduced to 50 percent and the Unit 2 reactor was manually tripped due to an impending loss of circulating water flow. The loss of circulating water flow was due to heavy kelp loading on the Unit 2 circulating water pump bay travelling screens.

The inspectors observed in the control room that the response actions taken by operations personnel were appropriate. Plant response to the trip was normal with the following exceptions: (1) Travelling Screen 2-1 failed due to the heavy kelp loading; (2) a number of condenser tube plugs were dislodged as a result of the loss of circulating water; and (3) two main steam safety valves (MSSVs) lifted prematurely - prior to the 10 percent atmospheric dump valves

opening. The abnormal lift pressures of the MSSVs is discussed further in Section 6.

2.2 Reactor Coolant Pump (RCP) 1-3 Containment Penetration Connection Box Fault

Background - On September 30, 1995, during the plant shutdown of Unit 1 for the start of refueling outage 1R7, a fault occurred and a fire started in the outside containment penetration connection box for RCP 1-3 following a pump start. The RCP was secured and the fire extinguished within several minutes of control room notification of the fire.

The licensee's investigation could not determine the reason for the electrical fault due to the extensive damage to the connector and cabling. A possibility was a loosened connection. Licensee corrective actions included: an operability verification of the RCP 1-3 containment penetration; replacement of the RCP 1-3 cabling from the switchgear to the connection box, and inspection and retightening of the other Unit 1 RCP connection box and motor terminations. Licensee personnel visual inspection of the Unit 2 RCP connection box terminations found no observable signs of degradation. The inspector noted that an action request has been initiated to more fully inspect and retorque the Unit 2 RCP connection box and motor terminations during the next unit refueling outage. Although the RCPs are not an engineered safety feature, failure of an RCP while at power would initiate a transient on the plant.

The inspector reviewed the event and concluded that operator recognition of the source of the fire and response to the fire were both timely and appropriate, and the licensee's followup actions were comprehensive in both addressing the root cause of the fault and its implications for the other RCPs in Unit 1 and in Unit 2.

2.3 Unit 2 Reactor Power Ascension and Plant Startup

On October 2, 1995, the inspector observed Unit 2 operators conduct a power ascension, including initiation of main feedwater following a manual reactor trip on September 23, 1995. The inspector noted that the portions observed were well controlled and operators' skills were good. The inspector did note that communications could be improved as repeat backs for common understanding among operators while operating both the primary and secondary plants were not routinely used. The Operations Director also noted this and the matter was debriefed in a later crew debriefing. The inspector considered this response adequate.

2.4 Core Offload

On October 5, 1995, the inspector observed portions of the Unit 1 core offload to the spent fuel pool including observations from the spent fuel pool area, control room, and containment. The inspector concluded overall that the evolution was well controlled, with the senior operator in containment

assuming control of the evolution, supported by licensed operators in the control room.

The inspector did note one instance, at the spent fuel pool, when an operator placed a status marker for an assembly just placed in the spent fuel pool in the wrong position on a status board staged to aid the personnel in tracking fuel assembly location. When questioned, the operator moved the marker to the correct location. Although the primary controlling document for fuel movement was the offload procedure, which listed all locations and designated fuel assemblies, the inspector considered errors in the status board could cause confusion later. Overall, the inspector concluded that the error was minor in nature, given the number of checks in place.

2.5 Open Fire Doors

On October 5, 1995, the inspector noted three fire doors (fire door into the Unit 2 Battery Room 2-1, fire door into Unit 2 Battery Room 2-3, and the fire door into a Class 1E Unit 1 and 2 480 Volt switchgear room) which were slightly open, during normal plant tours. The inspector was unable to determine how long these doors were in this condition. These doors provide fire isolation for the Unit 2 Class 1E batteries and 480 Volt switchgear. Unit 2 was in Mode 1 at the time. The licensee generated action requests to have the closing mechanisms adjusted. The inspector considered this a good response, but that operations personnel needed to be more observant of fire door deficiencies.

2.6 Inoperable Reactor Vessel Level Recorder

On October 3, 1995, during routine control board walkdown, the inspector noted that Train B level recorder on Post Accident Monitoring Panel (PAM) 1 (LR-204) for Unit 1 Reactor Vessel Level was inoperable because the paper roller had stopped, and the ink pens created an ink spot in one area. On October 29, 1995, the inspector noted that Train B level recorder on PAM 1 (LR-204) for Unit 2 reactor vessel level was inoperable because the pen was not inking. The inspector determined that these recorders were not required to be operable by Technical Specifications, but that vessel level was a parameter to be recorded as specified in Regulatory Guide 1.97. In response to the inspector's concerns the licensee initiated an action request and repaired the recorders in both cases. The inspector concluded the operators should have been more diligent in monitoring the PAM panels, which are located in the main control room.

3 ONSITE FOLLOWUP TO EVENTS (93702)

3.1 Unit 1 Loss of Offsite Power

On October 21, 1995, the Unit 1 operators were restoring electrical power to 12 kV Bus D in order to start the motor for Reactor Coolant Pump 14. The Unit 1 startup transformers were out of service at this time for preventive maintenance and offsite power to the unit was being provided through the main

transformers and Auxiliary Transformers 11 and 12. Unit 1 was in Mode 6 with the core reloaded at this time. When the operator closed the feeder breaker to Bus D from Auxiliary Transformer 11, the breaker opened and Auxiliary Transformer 11 failed catastrophically with the transformer oil and internals catching on fire. The main transformers automatically isolated and with the startup transformers out of service, caused a loss of offsite power to Unit 1. The three Unit 1 emergency diesel generators repowered the two class 1E trains. The operators restored shutdown cooling, which had been lost for approximately two minutes. The cause of the transformer failure was the presence of a grounding device (ground buggy) installed on Bus D, which permitted a large inrush of current when the feeder breaker was shut. The shift superintendent declared a Notice of Unusual Event based on the fire and loss of offsite power. The operating crew reestablished offsite power to the unit on October 22, 1995 and exited the Notice of Unusual Event.

The inspector responded to the site and remained on site until offsite power was restored approximately 16 hours after the event. The inspector observed licensee recovery actions from the control room, observed the failed transformer, and attended licensee recovery team meetings. Further details of this event and NRC inspection activities will be described in NRC Special Inspection Report 50-275/95-17.

4 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with the maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. Specifically, the inspector reviewed the work documentation or witnessed portions of the following maintenance activities:

<u>Unit 1</u>

- Install Freeze Seal to Prevent Leakage of FCV 128 in Preparation for Flow Test on Charging Pump 12
- Reactor Coolant Pump (RCP) 12 Motor Inspection
- RCP 11 Seal Rebuild
- Disassemble and Inspect FCV 41 (Main Steam Isolation Valve (MSIV))
- Auxiliary Saltwater Pump 1-1, Align Pump to Motor
- Main Feedwater Pump 1-2 Turbine Overhaul

Unit 2

- Troubleshoot Main Feedwater Pump and Auxiliary Building Air Conditioning and Vent Logic Panel

4.1 Replace the Actuator Pins and Perform an Internal Inspection of Main Steam Isolation (FCV 41)

On October 13, 1995, the inspector observed portions of licensee maintenance personnel disassembling, inspecting, and reassembling Valve FCV 41, using Work Order R0127628 01, which directed implementation of parts of Maintenance Procedure (MP) M-4.27 Rev. 1, "Main Steam Isolation Valve Disassembly, Inspection, and Reassembly." Valve FCV 41 is the number 1 main steam lead main steam isolation valve. The inspector concluded that the maintenance was performed satisfactorily, with the exception of final foreign material exclusion (FME) closeout of the system.

The inspector noted that step 6 of the work order was a signature step for quality control (QC) to verify FME prior to system closure. The inspector observed that a QC inspector verified the FME conditions inside the valve body and left the area before the valve top was rigged onto the valve. The maintenance technicians then left the area with a screened FME cover over the opening. The screen had about 1/2 inch square openings and could have allowed foreign material into the system. The craft then returned to the area and installed a new flexitalic gasket, and installed the cover. The inspector later interviewed supervisory QC personnel and determined that the intent of QC was to be present as the system was closed to ensure the signature step was valid, but that the status of the work was not understood by the QC inspector. This caused no QC reinspection to occur, after possible entry of foreign material into the system.

The inspector concluded that QC involvement in the FME was poor, but the event was of low safety significance in that the craft personnel performed a final inspection for foreign material.

4.2 Rebuild of Reactor Coolant Pump 11 Seal Package

On October 12, 1995, the inspector observed portions of licensee contractor personnel (a vendor representative and a contract machinist) disassembly, inspection, and reassembly of the RCP 11 seals in Unit 1 containment. Overall, the inspector concluded that the maintenance was performed satisfactorily.

The inspector noted one lapse in FME controls. The workers had previously removed and staged the number 2 seal cartridge, and had placed an FME cover over the seal injection port into the package. However, the seal injection exit port to the number 3 seal was left unsealed, with an opening that was too small to allow for an inspection of the inside. In response to the inspector's questions the personnel covered the opening. The inspector

considered the response adequate, but noted that the standard FME plan was not completely implemented.

5 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the Technical Specifications were reviewed on a sampling basis to verity that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure existed for performance of the surveillance tests; (3) the surveillance tests had been performed at a frequency specified in the Technical Specifications, and (4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillance were observed by the inspector during this inspection period:

Unit 1

- Surveillance Test Procedure (STP) M81-B, Rev. 2, Diesel 13, "Diesel Engine Generator Inspection (36 month Intervals)"
- STP M-9G, Rev. 21, Diesel 11, "Diesel Generator 24 Hour Load Test Hot Restart"
- STP P-CCP-A, Rev. 0 (XPR), CCP 12, "Performance Test of Centrifugal Charging Pumps"

Unit 2

- STP I-38-A.1, Rev. 2, "SSPS Train A Actuation Logic Test in Modes 1, 2, 3, or 4"

6 ONSITE ENGINEERING (37551)

6.1 Unit 1 Main Steam Isolation Valves Not Fully Closed During Core Alterations

Background - On October 10, 1995, the licensee discovered during fiber optic inspections of the interior of the Unit 1 MSIVs that two of the four valves were not fully seated. These were FCVs 41 and 42, the MSIVs for steam leads 1 and 2. These were found 1 1/2 inches (Valve FCV 41) and 1/4 inch (Valve FCV 42) off of their fully closed seats. These valves were manufactured by Schutte and Koerting and are 24-inch swing disc check valves (pneumatically opened and spring/system flow/gravity closed, non-angled). Each MSIV has an associated reverse flow check valve directly downstream from the MSIV and steam generator.

6.1.1 Discussion

The licensee and the inspector both noted that core alterations had taken place prior to October 10, 1995, and that Technical Specification 3.9.4 requires that during core alterations each penetration that provides a path from containment atmosphere to the outside atmosphere shall be either closed by an isolation valve or be capable of being closed by an operable automatic containment isolation valve.

The inspector reviewed numerous Action Requests, Nonconformance Report N0001932, "Violation of Containment Closure 1R7, MSIV Partially Open," licensee records of maintenance performed on the MSIVs, Vendor Technical Manual 663049-16, "Schutte and Koerting Company Figures 828AADC and 828 Main Steam Isolation Valve Sets," observed licensee maintenance on Valve FCV 41, and interviewed various licensee personnel.

The licensee performed core alterations without these MSIVs fully shut from 7:00 a.m. on October 4, 1995, to 11:00 a.m. on October 6, 1995 (for approximately 11 hours of this time period core alterations were not in progress). This is a violation of Technical Specification 3.9.4. The path from containment atmosphere to the outside atmosphere was through the steam generator secondary manways (Steam Generator 11 manway was removed for part of this period and Steam Generator 12 manway was removed for all of the period), and through two open 1 1/2 inch vent valves (Valves 1-2020 and 1-1021). This provided a path from between the MSIV and the reverse flow check valve to the downstream (from the steam generator) of the reverse flow check valve. Numerous system openings were present downstream of the reverse flow check valves.

6.1.2 Previous Event

During the Unit 2 cycle 6 outage, in August 1994, the licensee first identified, during fiber optic inspections, that the MSIVs might not fully close without system flow to aid in closing. The licensee then, via the action request process, initiated actions to revise the operations procedure for plant shutdown, for operation personnel to assure that the valves were fully closed prior to core alterations. This procedural change was not accomplished prior to the Unit 1 cycle 7 outage and the operators were unaware of the concern.

6.1.3 Vendor Lubrication Recommendations

The valve vendor recommended monthly lubrication of the pins in the linkage between the valve and the springs which assist closure. The licensee had not been performing this preventive maintenance (PM) since 1988, when it was deleted from the PM program. The licensee was in the process of determining the cause of the deletion of the lubrication PM. On October 13, 1995, the inspector visually inspected these pins on Valve FCV 42 and noted they were carbon steel, exposed to the outside environment, and had a moderate amount of

rust. The inspector concluded the failure to lubricate these pins monthly contributed to the incomplete closure of the valve.

6.1.4 Safety Significance

The inspector noted that the design basis fuel handling accident, a fuel element rupture, would not appreciably pressurize containment. However, the amount of radioactive iodine released over a period of time, if the design basis accident did occur when a pathway from containment existed, could have caused some unnecessary exposure to individuals.

6.1.5 Conclusions

The inspector concluded the failure to maintain adequate containment closure during core alternations was a violation of Technical Specification 3.9.4 (Violation 275/9515-01). The licensee's corrective actions in response to the Unit 2 cycle 6 findings were untimely and ineffective in preventing a recurrence of the problem. In addition the failure to lubricate the pins occurred about nine years ago, and was not reassessed when the Unit 2 cycle 6 failure was noted, indicating lack of a thorough review of the problem.

6.2 Component Cooling Water Heat Exchanger Fouling Factor

On September 30, 1995, the licensee conducted a performance test of Unit 1 residual heat removal/CCW Heat Exchanger 1-1 while in Mode 4 during the Unit 1 cooldown for its refueling outage. The licensee discovered that the heat exchanger was more efficient than assumed in the design basis accident analysis. Specifically, the heat exchanger exhibited a fouling factor significantly less than that assumed in the accident analysis (0.0001 fouling factor determined by testing vs. the 0.0008 fouling factor assumed in design calculations).. This could result in the residual heat removal system transferring more heat to the CCW system than originally designed such that design high temperature limits on the CCW system (120°F for no more than 20 minutes and a peak temperature no higher than 132°F) could be exceeded. The 132°F limit is based on a main steam line break inside containment and the 120°F limit is based on the recirculation phase following a loss-of-coolant accident.

The licensee initially instituted a compensatory measure of taking out-of-service one containment fan cooler unit in Units 1 and 2, to minimize possible heat input into the CCW system. At the end of the inspection period, the licensee was reanalyzing the main steam line break inside containment accident and the recirculation phase of a loss-of-coolant accident to determine exact measures needed to ensure that peak CCW temperature would remain within design limits.

The inspector reviewed various action requests, the test data, the Chapter 15 Final Safety Analysis Report analyses, and Nonconformance Report N0001930, "CCW System May Have Operated Outside Design Basis of Plant." The inspector concluded that the licensee's initial compensatory measure was appropriate.

The inspector will review the licensee's final analysis and any additional compensatory measures as Inspector Followup Item (IFI 275/9515-02).

6.3 Untested Contacts in the Plant Protection System

On October 19, 1995, the inspector noted during licensee discussions that the licensee had discovered contacts in the Unit 1 and Unit 2 plant protection system that had not been tested since they were installed in 1985. These were breaker open contacts for the secondary reactor coolant pump breakers (installed for containment penetration protection) and would open to initiate an RCP breaker position trip above 10 percent power (P-7).

The inspector reviewed Technical Specification 3.3.1, Table 3.3-1, the basis for this Technical Specification, the design package used to install the breakers and the contacts, Schematic Diagram 477846, Rev.6, "Reactor Coolant Pump 11," and interviewed licensee personnel. The inspector also discussed this issue with the Technical Specification Branch, NRR.

The inspector found that the contacts were installed in 1985 on both units during the first refueling outage. The contacts were added when the breakers were installed in response to the NRC requirement for redundant overcurrent protection for the RCP containment electrical penetrations. The contacts were functionally tested after installation, but had not been tested since. Testing of these contacts, and the primary breaker contacts, which are routinely tested, can only be done by actually tripping the associated RCP breaker. The inspector also found that the Technical Specification, which indicated that one channel per breaker was to be tested, referred to the primary breaker contacts only, as this was the breaker assumed in the design of the plant protection system.

Based on the above, the inspector concluded that testing only the primary breaker contacts met Technical Specification requirements. The inspector noted that the licensee generated Technical Specification interpretation 95-07, which also concluded that the Technical Specification was not applicable to these contacts. However, the inspector also concluded it would be a prudent practice to test these contacts when the primary contacts were tested, as they provided a redundant signal to the plant protection system of RCP breaker opening. The licensee stated their intention to test the Unit 1 contacts before the end of the cycle 7 outage and to incorporate functional testing of the contacts in both units each refueling outage.

The inspector considered this licensee engineering identification of this issue good and the response prudent.

6.4 Main Steam Safety Valve Setpoint Variation

6.4.1 Unit 1 Test Results

On September 13, 1995, the inspector observed the performance of portions of MP M-4.18, Revision 10, "Verification of Lift Point Using Ultra Star Lift Device For the Main Steam Safety Valves," on Unit 1's MSSVs. All five MSSVs on each main steam lead (20 total) were tested in preparation for refueling outage 1R7. All valves had been refurbished and reset on live steam during refueling outage 1R6 in April 1994. None of the valves had been called upon to operate in the intervening months. The results of MP M-4.18 showed the as-found lift pressures on 18 of the 20 MSSVs to be above their Technical Specification lift setpoint by greater than 1 percent. Thirteen of the 20 MSSVs exceeded their setpoint by greater than 5 percent. The licensee's analysis of these results found that the unit was operating outside of its design basis in that for a loss of load/turbine trip event, steam generator pressure could exceed 110 percent of the steam generator design pressure. In accordance with MP M-4.18, all valves were adjusted, as necessary, to obtain at least two consecutive lifts within 1 percent of their Technical Specification lift setpoint.

For the lift testing and verification of lift setpoints, the licensee used a hydraulic operated, lift-assist test device manufactured by AVK Industries (Ultra Star lift device) which was similar to the more commonly used Trevitest equipment (by Furmanite); however, the Ultra Star device uses an automatic acoustic device to determine the point at which the MSSV lifted. The test results were stated to be more reproducible. The licensee stated that extensive testing of the Ultra Star device had occurred to validate its performance using spare safety relief valves from the Diablo Canyon facility.

The inspectors participated in a conference call with the licensee, Region IV, and NRR personnel on September 15, 1995, to discuss the licensee's actions as a result of the test results. The licensee committed to test all of the Unit 2 MSSVs to verify operability and to retest selected valves on Unit 1. The licensee also expanded the Unit 1 outage work scope on the MSSVs to refurbish all 20 valves, reset each valve on live steam and perform additional testing prior to reinstallation.

6.4.2 Unit 2 MSSV Performance During Manual Reactor Trip

On September 23, 1995, following a manual trip of Unit 2, two of the lowest setpoint MSSVs lifted prematurely, prior to the lifting of the 10 percent atmospheric dump valves. Testing of the Unit 2 MSSVs was in progress when the plant trip occurred. The inspector noted that the two MSSVs that lifted prematurely had been adjusted to within 1 percent of the Technical Specification setpoint. The testing had determined that the valves were set too high and their setpoints were lowered.

Based upon the performance of the MSSVs following the plant trip, the licensee performed extensive additional tests of the Unit 2 MSSVs while the unit was in

Mode 3. The licensee determined from the additional testing that each of the MSSVs appear to have a characteristic lift pressure curve with a standard deviation between 1-2 percent. The inspector noted that the two MSSVs that lifted prematurely were adjusted based upon only two lift tests meeting acceptance criteria of within 1 percent of the setpoint, as specified by procedure MP M-4.18. The licensee concluded that the valve lift characteristics could not be adequately determined with only two lift tests and that this was insufficient data on which to base the acceptability of an adjustment. The inspector noted that the American Society of Mechanical Engineers code uses the acceptance criteria of two consecutive lift tests within setpoint tolerances to determine lift setpoint acceptability.

6.4.3 Followup Actions

On September 28, 1995, the inspectors participated in a second conference call between the licensee, Region IV, and NRR to discuss the licensee's findings and corrective actions. The licensee stated that extensive testing on the Unit 1 valves during the 1R7 refueling outage was planned in order to ascertain each valve's lift characteristic curve and procedure MP M-4.18 would be revised to require a sufficient number of lifts on each valve to ensure the as-left setpoint is within Technical Specification tolerances.

During the Unit 1 refueling outage, the licensee removed all 20 MSSVs for refurbishment and testing at the Westinghouse facility in Beaumont, California. Each of the valves was tested both on live steam and with the Ultra Star test device.

The licensee developed characteristic lift curves for all 20 valves using live steam and characteristic curves for ten of the valves using the Ultra Star equipment. The overall results were consistent with those obtained following the Unit 2 trip. However, a clear bias was noted between the live steam test results and those obtained using the Ultra Star equipment. The licensee determined that the bias was based upon both the test equipment limitations and the Ultra Star software parameters.

The licensee noted that the test facility utilized two different size accumulators to provide system pressure against the valve seat. The accumulators had capacities of 7 and 21 cubic feet. The licensee utilized the smaller accumulator for the initial tests. The relatively small size of the accumulator in relation to the relieving capacity of the MSSVs caused a rapid decrease in system pressure when the valve began to lift. This rapid decrease in system pressure translated into additional force being applied by the hydraulic assist device (to compensate for the reduced system pressure) to lift the valve far enough to trigger the acoustic monitor. This resulted in initial Ultra Star test results that were 20-25 psi higher than those obtained on live steam. The licensee compensated for this phenomenon by using the larger accumulator for subsequent testing and by increasing the system pressure by approximately 100 psi.

The licensee also noted that the Ultra Star software uses a spring constant for calculating the lift pressure. The spring constant was determined from testing of a single, benchmark valve. From discussions with the valve vendor, the licensee determined that the actual MSSV spring constants may differ from the benchmark valve, either higher or lower.

In addition to the valve characteristic baselining, the licensee has also stated that they were evaluating seat to nozzle bonding due to galling. If galling is confirmed, valve testing was planned to be performed utilizing different materials in the valve nozzle and seat. The licensee planned to also perform in-service testing of the Unit 1 MSSVs during the next operating cycle. The tests will be staggered to evaluate any time dependent effects on valve performance.

The licensee also requested an emergency Technical Specification amendment to expand the allowable valve setpoint tolerance to +/- 3 percent (+3/-2 percent for the lowest setpoint MSSVs). The Technical Specification change was consistent with the Westinghouse Standard Technical Specification. NRR approved the Technical Specification amendment request prior to the restart of Unit 2 with the request that the licensee provide a plan for increased testing of the MSSVs over the next operating cycle.

6.4.4 Conclusion

The results of the Unit 1 MSSV testing on September 13-15, 1995, raised a safety concern with regards to the MSSVs' ability to mitigate the consequences of an accident and preclude challenging the integrity of the steam generators. The inspector concluded that the licensee's corrective actions to perform tests on the Unit 2 MSSVs and expand testing of Unit 1 MSSVs during the refueling outage were timely and comprehensive to ensure the operability of the MSSVs. The licensee's long-term corrective actions should enhance the understanding of the phenomena that affects MSSV performance and should, thus, lead to improved reliability of these valves and may have generic implications.

6.5 230 kV Offsite Power Source

NRC Inspection Report 50-275/95-14 noted that one source of offsite power to Diablo Canyon had degraded due to loss of generation at Morro Bay and increased area loads. In that inspection report, the inspector reviewed the licensee's operability evaluation and concluded that the evaluation demonstrated short term operability, subject to the conditions set in the evaluation.

Subsequent to the inspectors review of this operability evaluation, one of the 330 megawatts (mW) generating units at Morro Bay, used to support 230 kV system operability, developed turbine problems and the unit had to be secured. A smaller 170 mW unit was started at Morro Bay to help maintain the 230 kV source of offsite power operable. In addition, the licensee blocked fast bus

transfer of one non-safety 12 kV bus in Unit 2, to reduce the potential load on the 230 kV system due to a Unit 2 trip.

The licensee completed a new operability evaluation (OE 95-06, Revision 4) based on the above described conditions, and concluded that the 230 kV system remained operable. The licensee based this evaluation on one of the smaller units at Morro Bay continuing to operate. However, failure of Unit 1 Auxiliary Transformer 1-1 required the licensee to add the Unit 1 shutdown loads on the 230 kV system.

The inspector requested operations management personnel to describe how they intended to monitor 230 kV system operability. The licensee provided the inspector with an evaluation, "Interim Diablo Canyon 230 kV Transmission system Guideline with Morro Bay Units 3 and 4 [330 mv each] out of service," dated October 20, 1995.

The inspector reviewed OE 95-06, Revision 4, and the interim operations guidelines. The inspector noted that due to the lack of supporting documentation, the inspector was unable to determine that the system would continue to remain operable when peak winter loads were present. The inspector had previously reviewed historical load data and determined that area fall and early winter loads were at least 15 percent below assumed worst case winter loads. Therefore, the current conditions at Diablo Canyon were not an immediate concern. Peak winter loads historically occur in January and February. The licensee agreed to provide the supporting data. The inspector will review of the supporting data as Inspector Followup Item (IFI 75/9515-03).

7 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during these evaluations.

7.1 Unattended Site Badge

On October 24, 1995, during routine tour of the Unit 1 turbine building, the inspector noted a protected area badge lying unattended near an opening to the main condenser waterbox. The inspector notified plant security. The badge was returned to a worker who was working in the waterbox, who was out of sight of the badge. Based on interviews, the inspector concluded that the badge was left outside the waterbox to avoid being lost in the waterbox. The inspector considered that this was not in accordance with the licensee program, which was to maintain custody of your badge at all times, as stated in Security Procedure SP 107, Revision 7, "Protected Area Identification Badge and Card Key Control," paragraph 2.2. This was a violation of this procedure. Licensee corrective actions included counseling of the individual by security personnel and by the individual's supervision, and reevaluating the individual's security program knowledge. This failure constitutes a violation

of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the Enforcement Policy.

7.2 Radiation Protection (RP)

During the inspection period, the inspectors noted several incidents in which licensee personnel failed to follow established RP procedures. The following are summaries of those incidents.

7.2.1 Unlabeled/Untagged High-High Radiation Area Debris Bucket

Background - On October 13, 1995, an RP technician discovered a high-high radiation area (HHRA) debris bucket tied off to the bridge crane without any radiological posting or labeling. A survey performed by the technician found a piece of debris in the bucket with an on-contact reading of 200 R/hr under water. The RP technician then posted and labeled the bucket in accordance with RCP D-610, "Control of Radioactive Materials," Revision 9A. The licensee's investigation found that the bucket was unattended and unlabeled for approximately 2 hours.

The licensee's corrective actions also included counseling the RP technicians involved and conducting tailboards of the event with RP shift crews.

Safety Significance - The lack of adequate controls for the HHRA debris bucket provided an opportunity for personnel to receive a significant dose had the bucket been unknowingly pulled from the reactor cavity. Each person in the containment is required to carry a personal electronic dosimeter that will alarm at a preset dose rate established by their governing radiation work permit. The licensee's evaluation concluded that the personal electronic dosimeter would have provided personnel adequate warning of the high dose rate to preclude an overexposure. Therefore, it is unlikely that personnel would have received a dose in excess of the limits of 10 CFR Part 20.

Conclusion - Although this event did not lead to an unintended exposure, it demonstrates a weakness in the licensee's control of radioactive material. Several other incidents identified by the inspector and the licensee during the reporting period, discussed in the following sections, are also attributable to poor procedural compliance. The failure to properly label the unattended HHRA debris bucket is not in adherence with licensee procedure RP D-610 and is a violation of the labeling requirements of Subsection 1904 of 10 CFR Part 20. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

7.2.2 Unlocked High-High Radiation Area Door

Background - On September 20, 1995, the licensee discovered the labyrinth door to the Unit 1 personnel escape hatch was unlocked. The unit was operating at 100 percent power at the time of the event. A surveillance leak test of the escape hatch airlock had been performed the previous day. Through discussions

with cognizant licensee personnel, the inspector determined that the labyrinth door (for the room outside of the escape hatch airlock) had been unlocked to perform the local leak rate test (LLRT) of the escape hatch airlock. This is a common licensee practice because the LLRT requires the inner airlock door to be dogged from inside containment during the test, thus precluding containment entry via the escape hatch. Following the test, an RP technician accompanied mechanical maintenance personnel into containment to remove the dogs on the inner escape hatch door. However, due to improper shift turnover and distraction of the RP foreman, the RP technician did not verify the labyrinth door locked prior to removing the dogs. The unlocked door was discovered when security personnel were performing a check of the door's card reader. Licensee procedure RCP D-221, "Control of Access to High Radiation Areas and High-High Radiation Areas," Revision 12, requires doors to high-high radiation areas to remain locked except when access is required under an approved work permit.

The licensee's corrective actions included locking the door, counseling of the RP foreman and conducting shift crew tailboards regarding access control to high radiation areas. The licensee stated they would also revise the LLRT procedure for the escape hatch airlock to direct operators to verify the labyrinth door is locked upon completion of the test.

Safety Significance - The inspector's review of the licensee's records determined that the labyrinth door was unlocked for approximately 26 hours. While a key card was required to open the labyrinth door, without the additional lock, the door provided a means for direct access to the Unit 1 containment while the unit was operating at 100 percent power. The inspector noted that although entry was possible, the escape hatch inner door is alarmed with annunciation in the control room and, therefore, operators would have been aware of any unauthorized entry. The licensee's review of the card reader log showed that no entries were made into the escape hatch labyrinth while the door was unlocked. The inspector considered that safety significance of the event was low, but had the potential to be a significant concern.

Conclusion - The inspector reviewed the applicable procedures controlling the LLRT evolution and concluded that the unlocked high-high radiation area door was not in adherence with licensee procedure RCP D-221. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

7.2.3 Inadequate Posting During Radiography

Background - On September 30, 1995, during radiography of the steam generator blowdown lines on the 115 foot level in the Unit 1 containment, the licensee identified that postings on the 91 foot level were not established in accordance with the radiography plan. The inspector interviewed licensee personnel and reviewed applicable records of the event. The inspector determined that the inadequate posting was a result of personnel involved with the evolution not understanding their responsibilities with regards to

establishing and verifying radiography boundaries. The inspector reviewed the controlling licensee procedure, RP1.ID7, Rev. 0, "Control of Radiography," and determined that personnel responsibilities are clearly delineated. Licensee corrective actions included shift crew tailboards discussing personnel responsibilities during radiography evolutions.

Safety Significance - The inspector noted that the unposted areas on the 91 foot level were all within a locked area posted as a high radiation area based upon operating conditions. Inadvertent entry to these areas was not possible. The inspector also noted that the inadequate posting was discovered by an RP technician unassociated with the radiography evolution who was performing a pre-work survey. Had the technician not been cognizant of the radiography, the surveys being performed should have precluded any overexposure. Therefore, while there is a concern for the proper posting of areas, the safety significance of this event is considered to be low.

Conclusion - The inspector concluded that unposted radiography boundary was not in adherence with licensee procedure RP1.ID7 in that the RP technician assigned to the radiography evolution did not adequately verify boundary postings established by the radiographer. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit
*W. H. Fujimoto, Vice President and Plant Manager, Diablo Canyon Operations
L. F. Womack, Vice President, Nuclear Technical Services
M. J. Angus, Manager, Regulatory and Design Services
*S. D. Allen, Engineer, Maintenance
C. R. Beck, Foreman, Technical Maintenance
*J. R. Becker, Director, Operations
S. Bednarz, Engineer, System Engineering
D. H. Behnke, Senior Engineer, Regulatory Services
F. Bosseloo, Assistant to Vice President, Nuclear Power Generation Business Unit
*W. G. Crockett, Manager, Engineering Services
*R. N. Curb, Manager, Outage Services
T. F. Fetterman, Director, Electrical and Instrumentation and Control Systems Engineering
T. L. Grebel, Director, Regulatory Support
D. L. Gouveia, Engineer, Nuclear Quality Services
*G. Goelzer, Shift Supervisor, Operations
C. R. Groff, Director, Secondary Systems Engineering
*C. D. Harbor, Engineer, Regulatory Support
R. J. LaVelle, Foreman, Mechanical Maintenance
R. J. Magruder, Shift Supervisor, Operations
*D. B. Miklush, Manager, Operations Services
*J. E. Molden, Manager, Maintenance Services
M. D. Nowlen, Senior Engineer, Technical Maintenance
P. T. Nugent, Senior Engineer, Regulatory Support
D. H. Oatley, Director, Mechanical Maintenance
R. P. Powers, Manager, Quality Services
*H. J. Phillips, Director, Technical Maintenance
*D. Taggart, Director, Nuclear Safety Engineering
R. G. Todaro, Director, Security
R. A. Waltos, Director, Balance of Plant Engineering
J. C. Young, Director, Quality Assurance

1.2 NRC Personnel

*J. J. Russell, Senior Resident Inspector, Acting
*S. A. Boynton, Resident Inspector
D. G. Acker, Senior Project Inspector

*Denotes those attending the exit meeting on November 2, 1995

2 EXIT MEETING

An exit meeting was conducted on November 2, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

CCW	Component Cooling Water
FME	Foreign Material Exclusion
FCV	Flow Control Valve
HHRA	High Radiation Area
kV	Kilovolt
LLRT	Local Leak Rate Test
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valve
MW	Megawatts
PAM	Post Accident Monitoring
PM	Preventive Maintenance
QC	Quality Control
RCP	Reactor Coolant Pump
RP	Radiological Protection